ECONOMICS of GAS FIELD DEVELOPMENTS

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Chapter 13

INTRODUCTION

Existing infrastructure

Most Cooper Basin producing oil and gas fields lie within a 75 km radius of the main processing plant at Moomba (Fig. 1.2). A considerable network of flowlines and trunklines connects fields to satellite facilities and thence to the processing plant at Moomba. Cooper Basin gas may comprise over 35% by volume of CO_2, so an important function of the Moomba plant is CO_2 removal. The plant also removes petroleum liquids and water to produce sales gas. Eleven gas satellites knock out free water and provide compression. Nine oil satellites remove free water from the oil before piping to Moomba.

The Moomba plant is designed to process 25.4 x 10^6 m^3 (900 mmscf) of raw gas and 6000 kL (42 000 bbl) of condensate and crude per day. A mixed stream of crude, condensate, LPG and a small volume of ethane is transported 659 km via pipeline to Port Bonython near the head of the Spencer Gulf (Fig. 1.1), where the streams are separated and sold.

Sales gas is sold from the Moomba plant to markets in Adelaide and Sydney. A second pipeline to Sydney transports ethane feedstock to the ICI petrochemical plant at Botany. The bulk of the remaining ethane is used in enhanced oil recovery projects; a minor amount is used as fuel at Port Bonython.

Access to infrastructure

The *Natural Gas Pipelines Access Act 1995* and the *National Gas Pipelines (South Australia) Act 1998* provide a right of access to licensed gas pipelines in South Australia. Access is subject to available capacity and negotiation with the pipeline owners, with arbitration available if negotiations fail. The *Petroleum Act 1940* also provides a mechanism for access to all licensed pipelines (including oil pipelines). None of the raw gas gathering trunklines in the Cooper Basin are required to be licensed (except for the pipeline from Ballera in South-West Queensland to Moomba and the Stokes to Mettika trunkline).

There is currently no legislative requirement to provide access to other upstream infrastructure beyond that provided in Part IIIA of the *Trade Practices Act 1974* (Cwlth). This issue is under discussion between jurisdictions as part of the current gas reform process. There is uncertainty as to whether these provisions apply to upstream petroleum facilities. However, there is nothing to prevent a third party entering into negotiations for access. Assuming that there is spare capacity in the system, the key issue will be the price paid for access to that capacity. The economic study of gas development in the Cooper Basin, by the former Mines and Energy Resources South Australia, was initiated to address this issue.

Access to markets

Gas provides ~75% of South Australia's primary energy needs. Gas is used directly by domestic, commercial and industrial consumers, and is also used to generate ~50% of the State's electricity requirements. Current South Australian supply contracts begin to expire from 2004, although supplementary supplies have been obtained for part of consumer need beyond that date. Contracts to supply New South Wales markets fall below requirements from ~2001. Meanwhile, forecast gas demands are expected to rise with the introduction of competitive energy markets, and increased industrial commercial expansion (Fig. 13.1). In addition, in a deregulated market there are opportunities for gas swapping arrangements which will allow gas to be sold into markets not physically connected to the field. A Cooper Basin explorer will have the option to sell gas into Queensland or Victorian markets. Opportunities therefore exist for new discoveries to be sold into expanding markets.

Economic study

A study of the cost of development of new discoveries in the Cooper Basin by parties independent of the current Cooper Basin Joint Venturers was carried out by McDonough (1997a, b).

A consulting engineering firm was engaged to provide costs to feasibility study level for the following development scenarios:

- gas field development totally independent of the current processing facilities, with and without recovery of LPG

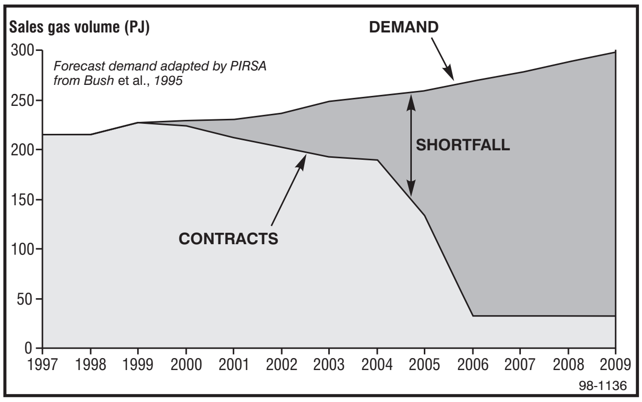

Fig. 13.1 *Forecast sales gas demand of New South Wales and South Australia versus current contracts.*

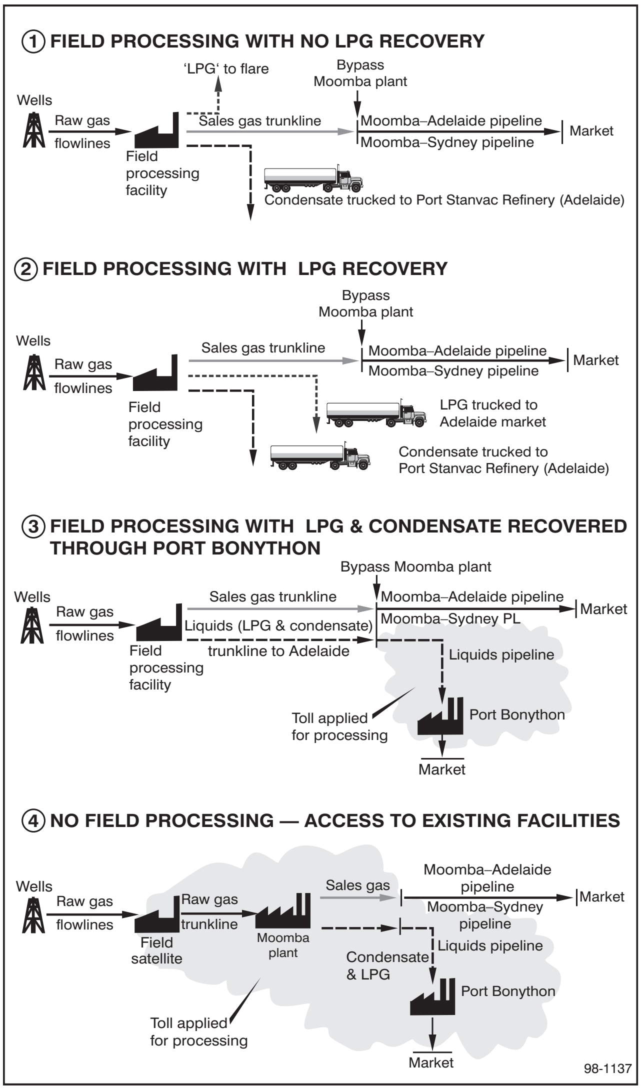

Fig. 13.2 Processing options for gas field discoveries post-1999.

- gas field development with access to the liquids pipeline and Port Bonython plant only (i.e. excluding the Moomba plant and satellite facilities)
- gas field development with access to all existing infrastructure

The different processing options are illustrated in Figure 13.2.

Cost studies were based on gas field production profiles which accounted for field size, deliverability, raw gas composition and distance from the head of the Moomba–Adelaide and Moomba–Sydney gas pipelines. Cost estimates were also provided for replacement of the existing facilities (satellite, trunkline, Moomba plant, liquids pipeline and Port Bonython plant), based on current technology. No optimisation of design was carried out and it was also assumed that exploration costs were sunk (cf. Ch. 14).

These data were used in cashflow studies of a range of gas field development options to provide estimates of:

- indicative tolling costs through the existing facilities using the replacement cost assuming modern technology and future estimated throughputs (a deprival value approach)
- minimum economic field size based on either stand-alone development or access to existing facilities

DISCUSSION

Cost of stand-alone processing

If access to existing facilities is not available or cannot be negotiated, new gas discoveries will need to be developed on a stand-alone basis. Obviously, it is not possible to anticipate the characteristics of every discovery made. Discovery scenarios were therefore chosen to describe an 'envelope' of possibilities, within which costs for likely discoveries will fall. Parameters which will impact on field development requirements and their values chosen are shown in Table 13.1. The distribution of gas wetness and CO_2 content are shown in Figures 8.1 and 8.2 respectively.

For this study, fields with high CO_2 have a CO_2 content greater than 30% by volume. Low CO_2 fields are those with a CO_2 content below 15% by volume. High liquids fields contain greater than 0.22 kL/m^3 (50 bbl/mmscf) of C_{5+} and 0.18 kL/m^3 (40 bbl/mmscf) of LPG. Low liquids fields contain less than 0.02 kL/m^3 (5 bbl/mmscf) of C_{5+} and 0.09 kL/m^3 (20 bbl/mmscf) of LPG. Fixed parameters were based on typical Cooper Basin figures.

It was assumed that a field would be fully developed before compression was installed. In addition, fields would be brought on-line in the year after they were discovered. Capital and operating costs were provided for the following:

- wellhead facilities and flowlines
- access roads and field camp
- compression
- processing plant
- trunklines
- condensate loading transportation

The economics of developing a cluster of small fields within a 10 km radius of a central processing field were also investigated (Table 13.1). For these cases, the maximum original gas-in-place (OGIP) of an individual field is 280 x 10^6 m^3 (10 bcf), with a maximum of five fields and a total OGIP of 1420 x 10^6 m^3 (50 bcf).

Deprival value pricing

It can be argued that to achieve efficient use of resources, the pricing regime for each section of the gas supply chain should be set by a competitive market or be set so as to imitate a competitive market.

Where a 'physical' monopoly exists, pricing principles for access to that facility must imitate a competitive market. In a truly competitive market there will be many facilities competing for business, and the price for access will fall between the operating cost of a facility (when there is abundant spare capacity in the system) and the deprival value cost of the facility (when there is no spare capacity in the system). To imitate a free market, the players must be free to negotiate within these bounds.

In its simplest form, the deprival value approach values the utility of a facility. This value is not the literal replacement cost of the existing plant (i.e. the cost to replicate the physical facility), but rather the cost of

Table 13.1 *Assumed parameters for new gas field discoveries.*

Parameter	Value
1. Raw gas composition	high liquids, high CO_2 high liquids, low CO_2 low liquids, high CO_2 low liquids, low CO_2
2. Field size	single field OGIP = 2830 x 10^6 m^3 (100 bcf) single field OGIP = 1420 x 10^6 m^3 (50 bcf) single field OGIP = 280 x 10^6 m^3 (10 bcf) multiple fields (located within 10 km radius of central field), individual field OGIP = 280 x 10^6 m^3 (10 bcf), total OGIP = 570, 850, 1130 and 1420 x 10^6 m^3 (20, 30, 40 and 50 bcf)
3. Maximum depletion rates	5% of OGIP/yr 10% of OGIP/yr
4. Gas processing requirements	sales gas specification according to *Natural Gas (Interim Supply) Act 1985* LPG flared or LPG recovered
5. Distance to transmission pipeline	20 km, 50 km, 100 km
6. Distance to existing infrastructure	20 km
7. Initial well rate	~210 x 10^6 m^3/day (6 mmscfd)
8. Well density	280 x 10^6 m^3/well (10 bcf/well)
9. Reservoir properties	depth = 2440 m, temperature = 121°C, pressure =24.1MPa (abs), flow capacity = 30.5 mD.m
10. Compression	Stage 1 = 7.9 MPa (gauge), Stage 2 = 3.8 MPa (gauge), Stage 3 = 1.7 MPa (gauge)
11. Transmission pipeline delivery pressure	6.9 MPa (abs)

replacing the service which is provided. It is assumed here that in a competitive market where little or no spare capacity exists, this is the cost of building a new facility using modern technology and current capacity requirements.

Cost of processing through existing facilities

The capital cost of replacing the utility of the existing facilities was also estimated in A$1995. This in turn was used to estimate both upper and lower limits on tolls. The upper limit is the price per unit volume of raw gas which must be charged to earn the plant owner's return on capital investment made to replace the utility of the existing facility. The lower limit is the operating cost of the plant. An independent producer will require access to:

- a satellite facility for initial water removal and compression (a typical large satellite with a capacity of 1130 x 10^6 m^3/yr (40 bcf/yr) is assumed)
- a trunkline to the Moomba plant (a trunkline length of 50 km is assumed)
- the Moomba plant itself, producing sales gas, ethane, LPG and condensate (the capacity required for the Moomba plant is based on the contract sales gas volume in 1999 (~215 PJ/yr), and the associated ethane and liquids production)
- liquids transport via the Moomba – Port Bonython liquids line
- processing and unloading at the Port Bonython plant

Based on the capital and operating costs required to provide this entire service, the deprival value toll was calculated to fall in the range $41 100 – 58 600/$10^6$ m^3 ($1200–1700/mmscf) of raw gas processed. The facility operating cost is estimated to be of the order of $13 500/$10^6$ m^3 ($380/mmscf) of raw gas.

The deprival value toll of processing liquids through the liquids pipeline and Port Bonython plant alone is estimated to be ~$70/kL ($11.10/bbl).

It should be noted that no allowance is made for apportionment of the toll price based on the processing requirements for differing raw gas compositions. For example, a liquids-rich, high CO_2 gas will require processing through the entire system, while liquids-poor, low CO_2 gas may require virtually no processing at all.

Cash flow analyses

The Net Present Value (NPV) of pre-tax cash flows achieved by developing gas fields under the various processing options was calculated, based on costs and prices in A$1995. A real discount rate of 12.5% was used to calculate the NPV. The sales gas price at the head of the Moomba–Adelaide and Moomba–Sydney pipelines was assumed to be $2.00/GJ. This was set at less than the current price to account for the possibility that gas prices will be driven down in a competitive market. Liquids prices are based on current domestic market prices. Costs of acquiring additional seismic were ignored, based on the assumption that the current seismic coverage in the Cooper Basin is sufficient. Exploration failures (i.e. unsuccessful wildcats) were not accounted for. A wellhead royalty of 10% was taken into account in accordance with the relevant provisions of the *Petroleum Act*.

An example of the minimum economic field size (i.e. the field size for which the NPV of the pre-tax cash flow exceeds zero) expressed in terms of million cubic metres (bcf) of recoverable raw gas for each of the cases investigated is shown in Table 13.2. The results assume that the field is located 50 km from the Moomba plant and 20 km from the nearest gas satellite. Minimum economic field size is quoted as a range to reflect the fact that the values presented are subject to uncertainty, depending on exploration company costs and rates of return, reservoir and gas properties, timing of developments, etc. The numbers presented are therefore indicative rather than definitive. However, they do provide an indication of relative economic field sizes for a given range of processing option (see also Fig. 13.3).

Given the assumptions listed, the following conclusions may be drawn:

- The economic viability of any discovery is highly dependent on the CO_2 and liquids content of the raw gas stream. Fields rich in liquids and low in CO_2 are the most economically attractive.
- If access to existing facilities (i.e. satellite–trunkline – Moomba plant – liquids pipeline – Port Bonython plant) is provided, liquids-rich fields with recoverable raw gas greater than 110–225 x 10^6 m^3 (4–8 bcf) will be economic (if situated within 20 km of an existing satellite, which is assumed to be 50 km from Moomba plant).
- If stand-alone facilities are used to develop a field, liquids-rich fields with recoverable raw gas exceeding 280–420 x 10^6 m^3 (10–15 bcf) will be economic (if situated within 50 km of a sales gas pipeline).
- Assuming the toll will fall in the range of $41 100 – 58 600/$10^6$ m^3 ($1200–1700/mmscf), it is always more economic to access the existing facilities than to build stand-alone facilities. The corollary of this is that if facilities access is allowed, smaller discoveries are economic. This conclusion is entirely to be expected, as the initial economic decision was to build the Moomba plant rather than a series of small plants scattered over the region.
- As a rule, the minimum economic field size with access to existing facilities is at least half of the minimum economic field size for stand-alone facilities (assuming similar processing requirements).
- Other factors which impact on economic viability are field size, deliverability and distance from existing facilities.
- For fields which are low in liquids, processing through existing facilities is generally uneconomic in the range of $41 100 – 58 600/$10^6$ m^3 ($1200–1700/mmscf), which is the expected toll range. However, it may be argued that lean fields would attract a lesser toll, as they would not require processing through the liquids pipeline and Port Bonython. (Conversely, one could then argue for a higher toll on rich fields to ensure that the return on total investment is constant.)
- For liquids-rich fields with an OGIP as large as 1000 x 10^6 m^3 (35 bcf; recoverable raw gas ~700 x 10^6 m^3 (25 bcf)), it is uneconomic to develop fields on a stand-alone basis unless LPG is flared. However, if facilities access is granted, the economics of the development are significantly improved and LPG is recovered. Therefore, access to existing facilities is desirable on both economic and resource conservation grounds.
- Access to existing facilities is also desirable on environmental grounds, as it removes the requirement for a proliferation of independent facilities, thereby minimising the environmental impact of new discoveries.
- For multiple fields clustered within a 10 km radius with OGIP of 280 x 10^6 m^3 (10 bcf) per field (recoverable raw gas 200–230 x 10^6 m^3 (7–8 bcf) per field), between two and five fields can be developed economically on a stand-alone basis. Again, the actual number is dependent on the composition, with low CO_2, high liquids fields being most economic.

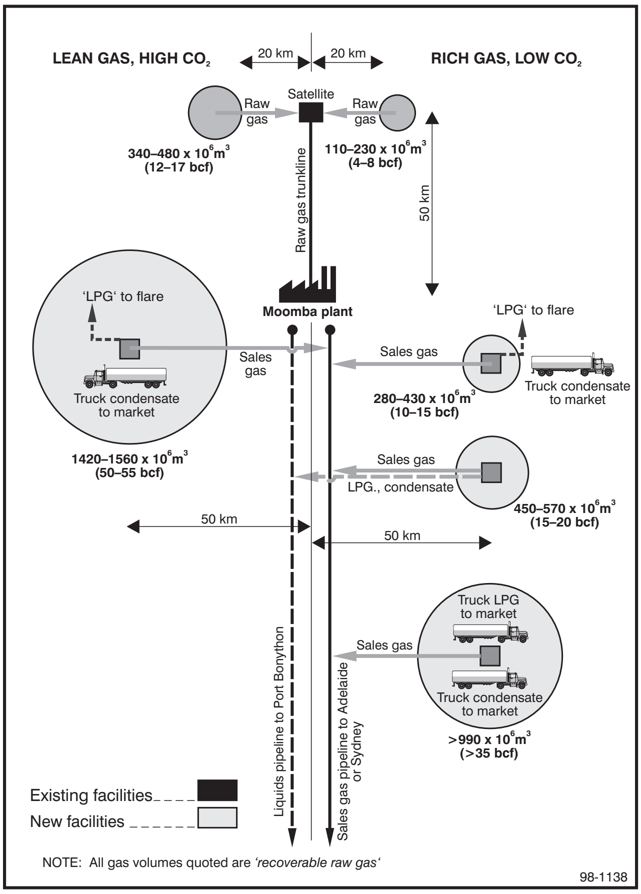

Fig. 13.3 *Schematic of limiting field sizes under various composition and processing scenarios (assumes 10% original gas-in-place depletion rate).*

CONCLUSION

Provided that new gas field discoveries made after 1999 in the Cooper Basin are of sufficient volume (of the order of 700 x 10^6 m^3 (25 bcf) recoverable raw gas), they will be economic to develop on a stand-alone basis if LPG is recovered. The economics of developing small fields on a stand-alone basis is also dependent on whether or not LPG is flared. For stand-alone plants it is more economic to flare LPG than recover it. This is undesirable on both

Table 13.2 *Minimum economic field size for fields located 50 km from Moomba.*

FIELD TYPE	MAXIMUM DEPLETION RATE	CO_2 CONTENT	LIQUIDS CONTENT	MINIMUM ECONOMIC FIELD SIZE (recoverable raw gas[a, b, c, d])									
				STAND-ALONE FACILITIES				FACILITIES ACCESS (LPG recovered @)					
				LPG not recovered		LPG recovered[e, f]		$35 300/ 10^6 m^3	($1000/ mmscf)	$49 400/ 10^6 m^3	($1400/ mmscf)	$63 600/ 10^6 m^3	($1800/ mmscf)
				10^6 m^3	(bcf)	10^6 m^3	(bcf)	10^6 m^3	(bcf)	10^6 m^3	(bcf)	10^6 m^3	(bcf)
single	5% of OGIP/yr	low	lean	710–850	(25–30)	not applicable	(not applicable)	450–570	(15–20)	uneconomic	(uneconomic)	uneconomic	(uneconomic)
		low	rich	450–570	(15–20)	710–850	(25–30)	110–230	(4–8)	110–230	(4–8)	110–230	(4–8)
single	10% of OGIP/yr	low	lean	480–620	(17–22)	not applicable	(not applicable)	280–430	(10–15)	uneconomic	(uneconomic)	uneconomic	(uneconomic)
		low	rich	280–430	(10–15)	450–570[g]	(15–20)[g]	110–230	(4–8)	110–230	(4–8)	110–230	(4–8)
single	5% of OGIP/yr	high	lean	1980–2120	(70–75)	not applicable	(not applicable)	510–650	(18–23)	uneconomic	(uneconomic)	uneconomic	(uneconomic)
		high	rich	770–910	(27–32)	990–1130	(35–40)	110–230	(4–8)	110–230	(4–8)	110–230	(4–8)
single	10% of OGIP/yr	high	lean	1420–1560[h]	(50–55)[h]	not applicable	(not applicable)	340–480	(12–17)	uneconomic	(uneconomic)	uneconomic	(uneconomic)
		high	rich	510–650	(18–23)	850–990[g]	(30–35)[g]	110–230	(4–8)	110–230	(4–8)	110–230	(4–8)
multiple[i]	71 x 10^6 m^3/yr (2.5 bcf/yr)	low	lean	850–990	(30–35)	not applicable	(not applicable)	marginal[j]	(marginal)[j]	uneconomic	(uneconomic)	uneconomic	(uneconomic)
		low	rich	280–430	(10–15)	570–710	(20–25)	200–430	(7–15)	200–430	(7–15)	200–430	(7–15)
multiple[i]	71 x 10^6 m^3/yr (2.5 bcf/yr)	high	lean	uneconomic	(uneconomic)	not applicable	(not applicable)	marginal[j]	(marginal)[j]	uneconomic	(uneconomic)	uneconomic	(uneconomic)
		high	rich	930–1080	(33–38)	1190–1390	(42–49)	200–430	(7–15)	200–430	(7–15)	200–430	(7–15)

a Based on project NPV calculated at 12.5% real discount rate.
b Gas price at head of pipeline $2.00/GJ, LPG price delivered to Adelaide $335/t, condensate price at Adelaide Refinery $160/kL ($25/bbl). All prices are in A$1995.
c Gas field is 50 km from Moomba and 20 km from nearest satellite.
d Recoverable raw gas based on recovery factor from nearest profitable case (generally 1400 x 10^6 m^3 (50 bcf)).
e For 'Stand-alone, LPG recovered' case, condensate and LPG are tolled through the Liquids Pipeline and Port Bonython at $70/kL ($11.10/bbl).
f For the case in which LPG is recovered by stand-alone facilities and then trucked to Adelaide (Fig. 13.3), fields with an OGIP of 1400 x 10^6 m^3 (50 bcf) or less will not be economic. Results for this processing option are therefore not included on this table.
g Estimate based on 'LPG not recovered' case.
h Estimate based on 'low CO_2, lean liquids' case.
i For multiple field cases, individual field OGIP is 280 x 10^6 m^3 (10 bcf) each.
j 'Marginal' implies that at a 12.5% discount rate, multiple fields of all sizes are close to economic. For multiple field case with lean compositions, minimum economic recoverable raw gas >420 x 10^6 m^3 (15 bcf) if project NPV is evaluated at a 10% real discount rate, with facilities access $35 300/$10^6$ m^3 ($1000/mmscf).

environmental and resource conservation grounds. However, if access to existing facilities can be negotiated, LPG is recovered and economics are markedly improved so that smaller fields will be able to be developed and more reserves recovered.

Given that recent discoveries have been relatively small, it is likely that the gas producer will require access to the existing facilities to produce fields which would otherwise be uneconomic. There is also high incentive for access from the public interest perspective, as it ensures that the economic recovery of the petroleum resource is maximised.

Third-party access to existing facilities should be negotiated on pricing principles which imitate a competitive market. Tolls in this instance should lie between the operating cost of the facility as a minimum and the deprival value cost as a maximum. Field sizes of the order of 110–225 x 10^6 m^3 (4–8 bcf) recoverable raw gas would be economic given access to existing facilities on the basis of deprival value ('replacement' cost) tolls.

This chapter is based on McDonough (1997a, b) which provided prospective explorers with a suite of data upon which to make initial decisions regarding the economics of gas exploration in the Cooper Basin. This study (McDonough, 1997a) is based on data available in the public and commercial arenas and thus demonstrates that it is possible for any company to develop their own data for development and negotiation purposes.